

15

RESOLUTION NO. _____

A RESOLUTION OF THE CITY COUNCIL OF THE CITY OF MILPITAS
AUTHORIZING THE EXECUTION AND DELIVERY OF THE
ELECTRIC PROGRAM WIND UP AGREEMENT

WHEREAS, the City of Milpitas was a member of the ABAG POWER Electric Aggregation Program; and

WHEREAS, the ABAG POWER Electric Aggregation Program was suspended on June 30, 2001; and

WHEREAS, ABAG POWER has retained certain funds owed to the City of Milpitas as an offset to certain risks and potential liabilities that would otherwise pass to the City of Milpitas; and

WHEREAS, ABAG POWER has received authorization from its Board of Directors to wind up the program and distribute remaining funds to members, while at the same time passing any remaining risk to members as well.

NOW, THEREFORE, BE IT RESOLVED, that the City Council of the City of Milpitas hereby authorizes the execution and delivery of the Electric Program Wind Up Agreement.

PASSED AND ADOPTED this 18th day of May 2004, by the following vote:.

AYES:

NOES:

ABSENT:

ABSTAIN:

ATTEST:

APPROVED:

Gail Blalock, City Clerk

Jose S. Esteves, Mayor

APPROVED AS TO FORM:

Steven T. Mattas, City Attorney

**AGREEMENT
between
ABAG POWER
and
City of Milpitas
to Wind Up Electric Program**

This Agreement between ABAG Publicly Owned Energy Resources (ABAG POWER), a joint exercise of powers agency created under the California Joint Powers Act (California Government Code §§6500 *et seq.*), and City of Milpitas (*City*), is made effective

RECITALS

- A. The *City* became a signatory to the Joint Powers Agreement creating ABAG POWER (JPA) (Attachment A, Exhibit 1) and a Member of ABAG POWER.
- B. ABAG POWER has been, and continues to be, staffed by employees of the Association of Bay Area Governments (ABAG).
- C. The *City* and ABAG POWER entered into the Direct Access Electric Aggregation Agreement (DA Agreement) (a form of the DA Agreement is at Attachment A, Exhibit 2). Under the DA Agreement, the *City* was a participant in the direct access electric aggregation program (Electric Program) until the Electric Program was suspended effective June 30, 2001 (the Electric Program is described in more detail in Attachment B).
- D. During the operation of the Electric Program and pursuant to the DA Agreement, each Member was obligated to pay, and did pay, to ABAG POWER a proportionate share of Electric Program costs and Working Capital needs (Electric Program costs and Working Capital needs are described in more detail in Attachment B).
- E. Upon suspension of the Electric Program, ABAG POWER retained funds (previously paid by the Members as described in paragraph D) to pay (1) identified potential Electric Program liabilities, (2) the costs of winding up the Electric Program, and (3) the costs of marshalling assets (amounts owed to ABAG POWER and Members) (liabilities, assets and costs are described in more detail in Attachments B and C).
- F. ABAG POWER has determined that it cannot, within a reasonable timeframe, (1) pay or eliminate certain potential liabilities, (2) marshal certain assets, or (3) eliminate identified potential liabilities associated with a major asset.

Therefore, ABAG POWER and *City* agree to wind up the Electric Program under the following terms and conditions:

- 1. Payment. *City* accepts as a true and proper accounting of all sums due to it from a wind up of the Electric Program the following specific and contingent sums:
 - a) Balancing Account – a sum to be determined pursuant to §4
 - b) Working Capital Deposits (\$83,865)
 - c) DA Credit – (\$316,870)

- d) ISO Escrow Deposit – to be determined pursuant to §5
- e) PX Escrow Deposit – to be determined pursuant to §5
- f) Wind Up Costs Hold Back – to be determined pursuant to §11

2. Payment Terms. ABAG POWER will pay to *City* the following sums:

- a) In complete payment of the Balancing Account owed *City*, such funds as are available as of July 1, 2004. Both the payment schedule and the amounts to be paid to *City* are determined by §4 of this Agreement.
- b) In complete payment of the Working Capital Deposits owed *City*, the sum of (\$83,865) within fifteen (15) days after the *City's* execution and return of an original of this Wind Up Agreement or after ABAG POWER's receipt of the "Qualifying Agreement" as defined in §10, whichever is later.
- c) In complete payment of the DA Credit owed *City*, the sum of (\$316,870) within fifteen (15) days after the latest of the following: i) the *City's* execution and return of an original of this Wind Up Agreement, or ii) after ABAG POWER's receipt of the "Qualifying Agreement" as defined in §10, or iii) receipt of the DA Credit from PG&E.
- d) In complete payment of the ISO Escrow Deposits owed the *City*, such funds that ABAG POWER may receive from time to time from the Northern California Power Authority (NCPA) until all funds available from the ISO Escrow Deposits are received. Both the payment schedule and the amounts to be paid to the *City* are determined by §5 of this Wind Up Agreement.
- e) In complete payment of the PX Escrow Deposit owed the *City*, funds that ABAG POWER may receive from time to time from NCPA until all funds available from the PX Escrow Deposit are received. Both the payment schedule and the amounts to be paid to *City* are determined by §5 of this Wind Up Agreement.
- f) In complete payment of the Wind Up Costs Hold Back, the amount determined under §11 of this Wind Up Agreement on or before July 1, 2010.

3. Funds Available for Disbursement and Allocation Ratios. Based on ABAG POWER's representation and warranties in §6 and such other documents as it deemed necessary, the *City* acknowledges that:

- a) funds available for disbursement were determined by ABAG POWER as described in greater detail in Attachment C. Further, *City* approves such determination.
- b) the payments described in §§1(a), (d), (e) and (f) of this Wind Up Agreement are the result of allocating all the Balancing Accounts, ISO Escrow Deposits, PX Escrow Deposits and Wind Up Costs Hold Backs available for disbursement among the Members in a ratio equal to each Member's electrical usage during the period of time such Member participated in the Electric Program to the total electrical usage by all Members who were participating in the Electric Program at the time of suspension ("Usage Ratio"). Further, *City* approves such allocation.
- c) Working Capital Deposits were made by the Members in accordance with ABAG POWER's financial records (see Attachment C). *City* acknowledges that the payment described in §1(b) of this Wind Up Agreement is the result of allocating the Working Capital Deposits available for disbursement among the Members in a ratio equal to the *City's* deposits to Working Capital to all Working Capital Deposits made by all Members who were participants in the Electric Program at the time of suspension ("Working Capital Ratio"). Further, *City* approves such allocation.

- d) the payment described in §1(c) is the result of allocating the DA Credit available for disbursement among the Members in a ratio equal to the CTC Reversals paid by *City* to all CTC Reversals paid by all Members ("CTC Reversal Ratio"). The method for determining said ratio is described in greater detail in Attachment C. Further, *City* approves such allocation.
4. Balancing Account Payment Amount and Schedule. The amount of the Balancing Account Payment to *City* is based on the total funds available for disbursement after payment of Working Capital Deposit and DA Credits and allocated to each Member by the Usage Ratio. ABAG POWER will have an independent financial audit conducted for fiscal year 2003-04 which will identify the total amount available for distribution. This amount will be allocated by the Usage Ratio and sent to *City* no later than March 31, 2005.
5. ISO Escrow Deposit and PX Escrow Deposit Amounts and Payment Schedule(s).
- a) ISO Escrow Deposit. The amount in the ISO Escrow Deposit available for disbursement to Members will be affected by regulatory and adjudicatory actions of the California Independent System Operator (ISO), California Public Utilities Commission (CPUC) or Federal Energy Regulatory Commission (FERC) (see Attachments B and D). As of December 31, 2003, the total amount in the ISO Escrow Deposit is Five Hundred Eight Thousand Two Hundred Fourteen Dollars (\$508,214). For a period of no less than two (2) years after the effective date of the Qualifying Agreement or December 31, 2006, whichever is later, ABAG POWER will monitor activities affecting fund balances in the ISO Escrow Deposit and will challenge or accept such recalculations at its sole reasonable discretion taking into account, among other factors, the amount of the recalculation, the probity of the underlying cause of the recalculation and the cost and probative value of challenging the recalculation.
 - b) PX Escrow Deposit. The California Power Exchange (PX) is in bankruptcy. As of December 31, 2003, the total amount in the PX Escrow Deposit is One Million Fifty-Six Thousand Five Hundred Six Dollars (\$1,056,506). For a period of no less than two (2) years after the effective date of the Qualifying Agreement or December 31, 2006, whichever is later, ABAG POWER will monitor activities affecting fund balances in the PX Escrow Deposit and will challenge or accept such recalculations at its sole reasonable discretion taking into account, among other factors, the amount of the recalculation, the probity of the underlying cause of the recalculation and the cost and probative value of challenging the recalculation. Upon its discharge from bankruptcy, the amount in the PX Escrow Deposit available for disbursement to Members will be determined.
 - c) Payments. NCPA may release portions of the ISO and/or PX Escrow Deposits to ABAG POWER from time to time. ABAG POWER will place such amounts in an interest bearing account until all funds have been released or December 31, 2006, whichever is earlier. The *City's* share will be determined using the Usage Ratio. ABAG will pay *City* its share of the amount in such accounts at that time. Any payments received by ABAG POWER after such disbursement will be paid to Electric Program Members if, in ABAG POWER's sole discretion, it is cost effective to do so.

6. ABAG POWER's Representations and Warranties.

- a) ABAG POWER represents and warrants that the descriptions provided in Attachments A, B and C are, to the best of ABAG POWER's knowledge, true and accurate for the purposes of (i) ABAG POWER performing as required under the Wind Up Agreement, and (ii) the Electric Program Members determining the accuracy, fairness and appropriateness of the distribution of funds contemplated by this Agreement.
- b) In some instances, the operation of the Electric Program may have deviated from the description contained in Attachment B or Attachment C or may omit some factors. ABAG POWER represents and warrants that any such deviations or omissions would not have had a material effect on the amounts to be disbursed or the allocation of those amounts to any individual Member.
- c) ABAG POWER represents that the analysis provided in Attachment D is, as of April 15, 2004, a fair statement of the risk that the contingent liabilities described in Attachment D will become actual liabilities. However, ABAG POWER neither guarantees the outcome nor represents that such analysis is the only conclusion that can be reached.
- d) Only Electric Program Members who execute this Agreement are entitled to rely on the information, representations and warranties set forth in this section and Attachments A through D, inclusive and any exhibits thereto.

7. City Due Diligence and Acceptance of Representations and Warranties. The City has reviewed this Wind Up Agreement, each of the Attachments and Exhibits and such other documents as it has examined and has determined that there is no additional information which it requires in order to make an informed decision on whether to accept or reject the terms of this Agreement or in order to determine the amounts to which it is entitled under the JPA or the DA. Therefore, the City hereby:

- a) Releases ABAG POWER and ABAG from any and all liabilities or claims which the City, or anyone claiming through it, may have against ABAG POWER or ABAG for damages, injury or additional proceeds from the wind up of the Electric Program.
- b) Releases ABAG POWER and ABAG from any and all liabilities or claims which the City, or anyone claiming through it, may have against ABAG POWER or ABAG for any damages or injury arising out of the City's participation in the Electric Program.
- c) Accepts the Contingent Risks described in Attachment D.
- d) Agrees to defend and indemnify ABAG POWER and ABAG against any claims made by any person claiming any rights through the City for damages resulting from the City's participation in the Electric Program, its execution of this Wind Up Agreement or the performance of any of its obligations hereunder unless such is caused by fraud, gross negligence or intentional misconduct of ABAG POWER or ABAG, or their respective members, directors, agents or employees.

8. Other Electric Program Members. The City acknowledges that each Member executing a Wind Up Agreement substantially identical to this Wind Up Agreement, excepting only the amounts set forth in §1 is a third party beneficiary of this Wind Up Agreement (hereinafter, a Member who executes a Wind Up Agreement is a "Third Party Beneficiary"). The City agrees that it will not make any claim against a Third Party Beneficiary for monies owed, or damages incurred by the City, as a result of the City's or such Member's participation in the Electric Program.

9. Covenants.

a) The *City* hereby covenants that it will do the following:

- 1) Notify ABAG POWER of any information, written notices, bills or any other communication regarding a Contingent Risk, described in Attachment D,
- 2) Cooperate with ABAG POWER and all Third Party Beneficiaries to eliminate, mitigate or resolve the possibility that a Contingent Risk will be triggered,
- 3) Cooperate with ABAG POWER and all Third Party Beneficiaries to fairly and reasonably allocate costs associated with any Contingent Risk that is actually incurred by the *City*, any Third Party Beneficiary or ABAG POWER, and
- 4) Pay to ABAG POWER its share of any Contingent Risk incurred by ABAG POWER, said share to be determined by the process described in subsection 9(c) of this section.

b) ABAG POWER covenants that it will:

- 1) Notify the *City* and all Third Party Beneficiaries of any information, written notices, bills or any other communication regarding a Contingent Risk, described in Attachment D,
- 2) Upon the occurrence of an event described in 9(a)(1) or 9(b)(1):
 - (i) the Board of Directors of ABAG POWER (Board) or the Executive Committee of the Board (Executive Committee), shall designate no fewer than five (5) and no more than eleven (11) Third Party Beneficiaries to form a Liability Allocation Committee (LAC).
 - (ii) The Board or the Executive Committee shall delegate to the LAC, the exercise of ABAG POWER's rights under Section 9.

c) ABAG POWER, on behalf of the LAC, covenants that the LAC shall:

- 1) Cooperate with the *City* and all Third Party Beneficiaries to eliminate, mitigate or resolve the possibility that a Contingent Risk will be triggered,
- 2) Cooperate with the *City* and all Third Party Beneficiaries to fairly and reasonably allocate costs associated with any Contingent Risk that is actually incurred by the *City* or any Third Party Beneficiary, and
- 3) The LAC shall confirm the reasonableness and fairness of the proposed allocation of costs by conducting a poll of Third Party Beneficiaries. If the proposed allocation is agreed to by a majority of Third Party Beneficiaries, then such plan is approved. For the purposes of this section, a majority is:
 - (i) More than fifty percent (50%) of the votes cast determined by counting each Third Party Beneficiary as having one vote, and
 - (ii) More than fifty percent (50%) of the votes cast determined by weighing each Third Party Beneficiary's vote by the amount disbursed to it under this Agreement.
- 4) If the Third Party Beneficiaries do not approve a cost allocation plan under Section 9 (c)(3) then the costs associated with a Contingent Risk will be allocated among all Third Party Beneficiaries in accordance with CTC Reversal Ratio for any costs associated with recovery of DA Credits and in accordance with the Usage Ratio for costs associated with recovery of energy and/or UDC costs (see Attachment D).

- 5) Receive from the *City* the share of any Contingent Risk incurred by the *City*, said share to be determined by the process described in subsection 9(3) or 9(4) of this subsection.
 - 6) Pay the liability.
10. Effectiveness of the Wind Up Agreement. This Wind Up Agreement becomes effective only if Members owed a total of Twenty Million Dollars (\$20,000,000) under §§1(a)-(c) execute a Wind Up Agreement substantially identical to this Wind Up Agreement, excepting only the amounts set forth in §1. The executed Wind Up Agreement which triggers this section is the Qualifying Agreement.
 11. Wind Up Cost Hold Back Funds. ABAG POWER will retain the sum of One Hundred Thousand Dollars (\$100,000) for the purposes described in §12. The funds will be separately accounted for by ABAG POWER and will be disbursed to Electric Program Members in accordance with §2(f) and allocated among Electric Program Members in accordance with the Usage Ratio.
 12. Permitted Uses of Wind Up Cost Hold Back Funds. ABAG POWER may use funds in the Wind Up Cost Hold Back to fund staff, consultants, attorneys or others engaged in any of the tasks described in §§5 and 9 of this Wind Up Agreement. ABAG POWER will send to each Electric Program Member an annual report on the use of funds and fund balances.
 13. Termination of DA Agreement. The DA Agreement between ABAG POWER and the *City* is hereby terminated.
 14. Assignment. This Agreement shall not be assigned, transferred, hypothecated, or pledged by the *City*.
 15. Amendment. §§1 and 2 of this Agreement may be amended at any time, but only by a writing signed by both parties. Any other section of this Agreement may be amended only by a writing signed by both parties and all Third Party Beneficiaries.
 16. Headings. The descriptive headings used in this Agreement are for convenience only and shall not control or affect the meaning or construction of any of its provisions.
 17. Controlling Law. This Agreement and all matters relating to it shall be governed by the laws of the State of California.
 18. Binding on Successors, Etc. This Agreement shall be binding upon the successors, assigns, or transferees of ABAG POWER or the *City* as the case may be. This provision shall not be construed as an authorization to assign or transfer this Agreement other than as provided above.
 19. Severability. Should any part of this Agreement be declared unconstitutional, invalid, or beyond the authority of either party to enter into or carry out, such decision shall not affect the validity of the remainder of this Agreement, which shall continue in full force and effect; provided that, the remainder of this Agreement can, absent the excised portion, be reasonably interpreted to give effect to the intentions of the parties.

20. Arbitration. Any disputes regarding the interpretation, effects, alleged breach or powers and duties arising out of this Agreement will be submitted to binding arbitration. An arbitration panel of three (3) individuals shall be formed as follows:

- a) Each Third Party Beneficiary and ABAG POWER shall have the right to submit the name and qualifications of an individual nominated for the panel. The individual shall be a member in good standing of the State Bar of California. ABAG POWER will compile a list of all such names, with the names of those submitted more than once, appearing as many times as they were submitted (List).
- b) Each Third Party Beneficiary which submitted a name and ABAG POWER, if it submitted a name, shall have the right to strike a name from the List. The order in which the Third Party Beneficiaries and ABAG POWER shall strike names shall be determined by lot.
- c) The striking process shall continue until only the names of three (3) qualified individuals are left. They shall constitute the arbitration panel.

IN WITNESS WHEREOF, the parties have executed this Agreement on the dates set forth below.

Dated: _____

MEMBER:

Signature

Print Name

Title

Dated: _____

ABAG PUBLICLY OWNED ENERGY
RESOURCES (ABAG POWER):

Eugene Y. Leong, President

Approved as to Legal Form and Content:

By:

Kenneth K. Moy, Legal Counsel
ABAG Public Owned Energy Resources (ABAG POWER)

ATTACHMENT B

BACKGROUND

The Members formed ABAG POWER to operate, among others, the Electric Program. Each Member agreed to pay its share of all costs associated with the Electric Program and appointed ABAG POWER as its agent for the purposes of implementing the Electric Program.

The Electric Program operated under rules promulgated by the California Public Utilities Commission (CPUC), the California Independent System Operator (ISO), the California Power Exchange (PX) and the conventions and practices established by each of the aforementioned entities and by PG&E pursuant to AB 1890 ("Deregulated Market"). The Electric Program provided electricity to accounts specified by each Member under the JPA and DA Agreement as defined in the body of the Wind Up Agreement to which this document is attached.

ABAG POWER is a separate legal entity under the JPA. Each Member is represented on the ABAG POWER Board of Directors (Board). ABAG POWER continues to operate a natural gas aggregation program. All program decisions are made under the policy direction of the Board or the Executive Committee of the Board.

ABAG POWER used the following resources from the described entities in order to implement the Electric Program:

- (a) electrical energy from various generators and brokers,
- (b) distribution and other services from PG&E,
- (c) electric grid services (reliability and control) from the ISO,
- (d) schedule coordination (as described below) from NCPA,
- (e) billing services from Arizona Public Services (APS), and
- (f) administrative and support services from the Association of Bay Area Governments (ABAG).

In addition, ABAG POWER procured occasional services (not relevant to the wind up of the Electric Program) during the operation of the Electric Program. Occasional services included, but are not limited to, financial auditors, attorneys, electric meters sales and installation and meter reading services.

ABAG POWER paid for the resources described above with payments made by the Members. In order to maintain cash flow liquidity, Members funded Working Capital reserves for ABAG POWER through both their monthly payments for electricity and through Working Capital "calls."¹

Under the Deregulated Market, all electric aggregators were required to pay for ancillary electric services (transmission and distribution costs, system reliability services, etc.) through the ISO. In addition, energy purchases made from the PX required certain security deposits be maintained. The PX and the ISO required such payments be made through a recognized "scheduling coordinator."

¹ At the beginning of the program, ABAG POWER billed Members on an estimated "levelized" schedule that included amounts necessary to fund a working capital reserve. This methodology was later abandoned in favor of a monthly bill based on actual expenses and a separate series of calls for working capital contributions from the Members.

ABAG POWER retained NCPA to act as the scheduling coordinator for the Electric Program. NCPA also served as scheduling coordinator for its own members. The Deregulated Market required electric aggregators to deposit funds into two escrow accounts, one with the ISO and the other with the PX. (The latter deposit was only required if the electric aggregator purchased energy from the PX.) NCPA made such deposits on behalf of ABAG POWER. The ISO and PX drew down on the escrow accounts to pay for monthly energy (PX), if any, and electric grid service charges (ISO). The escrow deposit funds were maintained at a level sufficient to pay for 90 days (estimated) worth of energy and ancillary service charges. ABAG POWER paid NCPA the funds necessary to maintain the escrow deposit funds at the required levels. The amounts in the funds were held by NCPA in trust for ABAG POWER.

WIND UP PLAN

Upon the suspension of the Electric Program, ABAG POWER's billing agent, APS compiled charges attributed to Member accounts. This data indicated that there were service charges for transmission and other services from PG&E (UDC Charges) that had not been invoiced to ABAG POWER in the approximate amount of Three Million Three Hundred Thousand Dollars (\$3,300,000). ABAG POWER also experienced a one-week period in August 2000 during which it did not purchase electricity for the Members due to unstable market conditions. Members continued to receive power. ABAG POWER has not been invoiced for the costs of the energy consumed during this period. ABAG POWER estimates this cost to be approximately One Million Four Hundred Thousand Dollars (\$1,400,000) (based on load profiling and prevailing energy costs).

Initially, ABAG POWER retained the funds it held in its own accounts to pay for the uninvoiced UDC Charges and energy charges, and to pay ongoing wind up costs. ABAG POWER has concluded that:

- (a) some of the uninvoiced UDC Charges were included in the Direct Access Credit calculation (see below),
- (b) the balance of the uninvoiced UDC Charges have not been, and may never be invoiced to ABAG POWER (for further discussion see Attachment D), and
- (c) the energy charges have not been, and may never be invoiced to ABAG POWER (for further discussion see Attachment D).

Based on the foregoing, ABAG POWER is concluding the wind up of the Electric Program without settling the potential liabilities for UDC Charges and energy described above.

Further, ABAG POWER has concluded that the funds held by NCPA will not be released in the foreseeable future (see below). Therefore, ABAG POWER is concluding the wind up of the Electric Program without having received all of the funds held by NCPA in trust for ABAG POWER in the ISO Escrow Deposit and the PX Escrow Deposit.

Finally, ABAG POWER has settled its claim against PG&E for the Direct Access Credits (see below). ABAG POWER is distributing the funds from the settlement as part of the wind up.

DIRECT ACCESS CREDIT

The Direct Access Credit results from the intersection of CPUC regulations and extraordinarily high prices for electricity in 2000. The following is excerpted from a CPUC draft document that describes what the Direct Access Credit is and how it is derived.²

"Since 1998, PG&E and SCE have offered service to two distinct classes of customers. Bundled service customers received the full range of electric services from the utilities, which include energy procurement and delivery. PG&E and SCE customers could also choose, under the DA option, to purchase energy from an electric service provider (ESP). PG&E and SCE continue to deliver electricity to both [Direct Access] and bundled service customers.

A. Rate Freeze

Total rates were frozen at levels in effect on June 10, 1996 for all customers. Bundled service customers paid these frozen rates for the duration of the transition period (January 1, 1998 through March 31, 2002 or a Commission-authorized earlier end date). These frozen tariff rates included a generation rate component. The generation rate was unbundled into a market price and a competition transition charge (CTC) component. The CTC was calculated residually as the difference between the fixed generation rate component and the market price, where the market price was based on the utility's cost of procuring power from the PX and the California Independent System Operator (ISO). All customers pay the CTC and the CTC revenues were to be used to pay for the utility's stranded generation costs, also known as transition costs.

B. The Avoided Cost Credit

The utilities calculated a market price for billing purposes utilizing the cost and quantities of power purchased from the PX. This PX price was used to determine the contribution to the recovery of CTC (when compared to the generation rate component of frozen rates) and also represented the utilities' avoided cost of procuring energy. The PX component of the generation rate was either applied to recover the cost of purchasing power for bundled service customers or given as a credit to DA customers. The credit reflected the fact that DA customers had chosen to procure their energy through an ESP rather than the utility. So long as the market price, or DA credit, remained below the generation component of the customer's frozen rate, the DA customer continued to make a contribution to CTC in exactly the same manner as a similarly situated bundled service customer.

C. The Zero Minimum Bill Provision

Because the DA credit was based on the market price from the PX, it was possible that the credit would exceed either the generation rate component or the entire bill. If the PX credit exceeded the generation rate component, there was a negative CTC, i.e., no contribution to recovery of stranded costs. If the PX credit exceeded the entire amount of the bill, meaning that the PX credit was greater than the sum of the generation, distribution, transmission, public purpose, and the other rate components, there would be a negative bill. In other words, the DA customer would receive a credit for the entire utility bill. This is also known as a "credit" bill.

² See Attachment D description of 1998 RAP – Draft Decision.

Prior to June 1999, under the adopted tariffs, DA customers receiving the PX credit could experience, at a minimum, a monthly bill of \$0. In D.99-06-058, the Commission eliminated the zero minimum bill provision. The elimination of the zero-minimum bill provision allowed DA customers to receive the entire PX credit even if it resulted in a negative (credit) bill. Prior to market dysfunctions in mid 2000, PX credits in excess of total monthly charges were generally carried over to succeeding months and were netted against positive bills.

The dysfunction of California energy markets in 2000 through early 2001, undermined the original basis for calculating the DA credit. The prices charged the utilities during the waning days of the PX were substantially higher than the cost of producing the energy; were regularly higher than the generation component of frozen rates; and in fact, were frequently so high that the DA credit exceeded the entire amount of a DA customer's bill for the services the DA customer did take from the utility and the generation rate component. The PX collapsed in January 2001."

Upon the suspension of the Electric Program, PG&E owed ABAG POWER approximately Twenty-One Million Three Hundred Thousand Dollars (\$21,300,000) in unpaid Direct Access Credits. ABAG POWER filed a complaint with the CPUC to collect the credits. The CPUC Complaint was stayed when PG&E filed for Chapter 11 bankruptcy in April 2002. ABAG POWER settled its claim against PG&E for Seventeen Million Dollars (\$17,000,000) plus bankruptcy required interest at the rate of 4.19% per annum. PG&E has paid Seventeen Million Dollars (\$17,000,000) in principal and Two Million Four Hundred Thousand Dollars (\$2,400,000) in interest in fulfillment of the settlement.

ATTACHMENT C

FINANCIAL INFORMATION

ABAG POWER settled its DA credit claim with PG&E in late 2002 for \$17.0 million plus interest at an annual rate of 4.19% to accrue beginning December 1, 2000. Accordingly, staff reflected this settlement in the financial reports for fiscal year ending June 30, 2003, with all other necessary adjustments incorporated therein to prepare for winding up the Electricity Pool and distributing cash on hand to members by June 30, 2004. The Executive Committee approved all these book adjustments prior to the year-end close, and our independent auditors have completed their audit of the June 30, 2003 financial reports. They expressed an unqualified opinion on these reports with no audit adjustments. Since ABAG POWER has received payment in full plus accrued interest from PG&E for settlement of the DA credit claim in April 2004, the payment dates as listed on the next page are realistic.

Based on the audited financial reports of ABAG POWER for the year ending June 30, 2003 that were duly approved by the Executive Committee at its meeting held on February 18, 2004, the Electricity Pool has \$23.8 million in total assets available for distribution to its members (see Exhibit A). Total assets will continue to: (a) Increase by accrued interest from the PG&E settlement and from the pool's investment in the Local Agency Investment Fund, and (b) Decrease by operating expenses necessary to wind up the pool.

On October 27, 2003, the ABAG POWER Board of Directors approved the methodology for winding up the electric program and distributing funds. In accordance with this process, funds in the Electricity Pool will be distributed in three categories.

Payable to Members	Description	Basis of Distribution
PG&E Distribution	DA Credit settlement less approximately \$740,000 (see table on next page)	Total CTC reversal collected from each member
Other	Working capital	Total working capital collected from each member
Members' Balancing Account	Accumulated operating Surplus/deficit	Total KWH usage

The following table shows balances of total audited assets and proposed disbursements as of June 30, 2003 and current balances as of April 15, 2004 and target dates of distribution.

	Audited Balances 6/30/2003 (\$'MM)	Interim Balances 4/15/2004 (\$'MM)	Status	Target Distribution Date
Total Assets	<u>23.84</u>	<u>24.36</u>	Will increase by accrued interest net of operating expenses	As stated below
<u>Payable to Members</u>				
PG&E Distribution*	18.27	18.83	Will not change	6/15/2004
Other	5.41	5.41	Will not change	6/15/2004
Members' Balancing Account	0.16	0.12	Will decrease by operating expenses	03/31/05, after the FY 04 audit
Total Disbursements	<u>23.84</u>	<u>24.36</u>		

* On February 18, 2004, the Executive Committee approved: (a) retaining \$100,000 from the DA Credit settlement to pay for wind up expenses after June 3, 2004 (the residual balance in the hold back fund will be distributed before July 1, 2010), and (b) applying approximately \$640,000 from the DA Credit settlement to pay "Other" (Working Capital).

Exhibit B to Attachment C

ABAG POWER Electric Program Allocation & Distribution

(As of April 15, 2004)

Members	Grand Total Usage (kWh) (1)	Usage %	Original CTC Reversals	Streetlight Correction	Net CTC Reversals	CTC Reversal %	DA Credit Distribution (2)	Total Working Cap. Deposits (3)	Total Distribution (4)
City of Albany	3,269,408	0.35%	\$ 70,514	\$ (37,804)	\$ 32,710	0.20%	\$ 37,440	\$ 13,725	\$ 51,165
Town of Los Altos Hills	314,682	0.03%	4,274		4,274	0.03%	4,892	6,099	10,991
City of Antioch	49,175,835	5.21%	696,703	(122,580)	574,122	3.51%	657,142	167,352	824,494
City of Arcata	3,562,992	0.38%	79,173	(25,043)	54,131	0.33%	61,958	29,796	91,754
Town of Atherton	1,898,831	0.20%	27,998		27,998	0.17%	32,047	18,123	50,170
City of Benicia	12,064,815	1.28%	251,386	(74,333)	177,053	1.08%	202,655	88,075	290,730
City of Berkeley	2,696,431	0.29%	193,082		193,082	1.18%	221,003	61,428	282,431
County of Butte	19,049,605	2.02%	376,505		376,505	2.30%	430,948	119,314	550,263
City of Cloverdale	5,113,484	0.54%	103,456		103,456	0.63%	118,416	35,056	153,473
County of Monterey	52,383,320	5.55%	531,804	(1,915)	529,889	3.24%	606,512	225,794	832,306
County of Contra Costa	138,139,814	14.65%	2,748,664	(23,395)	2,725,269	16.66%	3,119,351	545,198	3,664,549
City of Cotati	2,629,895	0.28%	37,545	(130)	37,415	0.23%	42,825	25,935	68,760
City of Cupertino	13,694,587	1.45%	234,959	(63,383)	171,575	1.05%	196,386	92,444	288,830
City of Daly City	41,194,260	4.37%	1,417,366	(165,064)	1,252,303	7.65%	1,433,390	130,117	1,563,507
City of Davis	2,207,730	0.23%	34,764	(21,751)	13,013	0.08%	14,894	20,009	34,903
City of El Cerrito	3,404,997	0.36%	57,838		57,838	0.35%	66,202	32,320	98,522
City of Foster City	13,133,829	1.39%	301,085	(109,981)	191,104	1.17%	218,738	68,016	286,754
Golden Gate Bridge District	13,208,235	1.40%	355,647		355,647	2.17%	407,074	45,318	452,392
City of Gonzales	3,741,591	0.40%	54,963	(2,040)	52,923	0.32%	60,576	36,264	96,840
City of Half Moon Bay	1,888,466	0.20%	25,108		25,108	0.15%	28,738	14,071	42,810
H.A.R.D.	8,386,287	0.89%	135,566		135,566	0.83%	155,170	84,911	240,080
City of Hercules	5,239,548	0.56%	89,938	(12,002)	77,935	0.48%	89,205	56,859	146,064
Town of Hillsborough	7,611,796	0.81%	107,637		107,637	0.66%	123,201	76,024	199,226
Housing Auth. Co. of Alameda	1,248,447	0.13%	23,420		23,420	0.14%	26,806	18,003	44,810
City of Los Altos	5,152,008	0.55%	73,385		73,385	0.45%	83,996	41,289	125,285
Los Trancos Co. Water District	670,686	0.07%	4,646		4,646	0.03%	5,318	6,698	12,016
City of Menlo Park	11,546,594	1.22%	267,524	(71,150)	196,373	1.20%	224,769	82,908	307,678
City of Millbrae	5,241,722	0.56%	103,562	(58,891)	44,670	0.27%	51,130	37,973	89,102
City of Mill Valley	10,532,429	1.12%	204,374	(26,042)	178,332	1.09%	204,119	94,946	299,065
City of Milpitas	11,013,448	1.17%	276,838		276,838	1.69%	316,870	83,865	400,734
Town of Moraga	1,768,987	0.19%	12,800		12,800	0.08%	14,650	12,503	27,153
County of Napa	14,477,518	1.53%	383,200	(1,297)	381,903	2.33%	437,128	73,627	510,755
City of Newark	8,728,855	0.93%	174,076	(85,209)	88,868	0.54%	101,718	81,536	183,254
City of Orinda	1,602,274	0.17%	19,135	(1,122)	18,013	0.11%	20,618	18,433	39,051
City of Pacifica	8,145,529	0.86%	165,604	(67,092)	98,512	0.60%	112,757	49,496	162,253
City of Patterson	6,354,738	0.67%	222,030	(3,126)	218,904	1.34%	250,558	35,892	286,450
City of Petaluma	36,118,882	3.83%	457,781	(120,246)	337,535	2.06%	386,344	196,030	582,373

Exhibit B to Attachment C

ABAG POWER Electric Program Allocation & Distribution

(As of April 15, 2004)

Members	Grand Total Usage (kWh) (1)	Usage %	Original CTC Reversals	Streetlight Correction	Net CTC Reversals	CTC Reversal %	DA Credit Distribution (2)	Total Working Cap. Deposits (3)	Total Distribution (4)
City of Pinole	9,446,916	1.00%	252,199		252,199	1.54%	288,668	22,875	311,543
City of Pleasanton	28,757,666	3.05%	511,098	(133,465)	377,633	2.31%	432,240	182,101	614,341
R.A.F.C.	11,869,270	1.26%	225,935		225,935	1.38%	258,606	155,745	414,351
City of Salinas	26,619,689	2.82%	466,324	(262,362)	203,961	1.25%	233,455	133,488	366,943
City of San Carlos	6,896,150	0.73%	160,947	(65,873)	95,074	0.58%	108,822	42,589	151,412
City of San Leandro	32,799,800	3.48%	686,521	(199,508)	487,013	2.98%	557,436	157,723	715,160
City of San Mateo	29,749,102	3.15%	688,758	(276,868)	411,890	2.52%	471,450	189,375	660,825
County of San Mateo	98,391,072	10.43%	2,109,359	(71,151)	2,038,208	12.46%	2,332,939	604,514	2,937,453
City of San Pablo	6,222,193	0.66%	82,505		82,505	0.50%	94,436	47,404	141,840
City of Santa Rosa	54,963,333	5.83%	854,324	(194,168)	660,156	4.04%	755,616	296,993	1,052,609
City of Saratoga	2,899,035	0.31%	38,110	(2,929)	35,181	0.22%	40,269	24,666	64,934
County of Sonoma	4,805,048	0.51%	53,841		53,841	0.33%	61,627	39,725	101,352
South Co. Fire Authority	601,994	0.06%	13,289		13,289	0.08%	15,211	5,979	21,189
City of Union City	1,911,061	0.20%	59,927		59,927	0.37%	68,592	8,269	76,861
City of Vacaville	5,162,752	0.55%	93,369		93,369	0.57%	106,871	57,524	164,394
City of Vallejo	60,985,603	6.47%	1,212,306		1,212,306	7.41%	1,387,609	353,803	1,741,413
West County Wastewater Dist.	13,699,914	1.45%	459,806	(9)	459,797	2.81%	526,285	136,567	662,852
Town of Windsor	16,479,736	1.75%	328,111	(1,362)	326,749	2.00%	373,998	90,454	464,451
City of Winters	4,366,833	0.46%	40,360		40,360	0.25%	46,196	39,032	85,228
GL WriteOn			(2)		(2)		(2)		(2)
Total (4)	943,239,722	100%	18,661,435	(2,301,293)	16,360,141	100%	18,725,870	5,414,272	24,140,142

Notes

(1) Total usage for entire program period. Data from billing agent (APS) for billing periods 4/98 - 7/01.

(2) Total of Net CTC Reversals, plus interest on bankruptcy claim, minus \$100,000 hold back amount. This is equivalent to the bankruptcy claim principal and interest (\$19,465,729), less \$639,859 allocated for repayment of Working Capital, minus \$100,000 hold back amount.

(3) Total of "Working Capital Client Deposits" and "PX and ISO Client Deposits."

(4) Does not include Members Balancing Account, or ISO and PX escrow deposits with NCPA.

ATTACHMENT D

CONTINGENT RISKS

RISK ANALYSIS

Attached as Exhibit A is a table setting forth ABAG POWER's best reasonable effort at estimating the maximum reasonable liability (in total for the Electric Program) for each of the listed contingent liabilities. The table allocates total liability of the program to individual Members in accordance with the usage ratio, or CTC Reversal ratio, as appropriate. The allocation is for illustrative purposes only. ABAG POWER does not have sufficient information on which to base an estimate of how the entity imposing the liability would allocate the liabilities or how ABAG POWER and the Members ought to react to such allocation.

A. UNINVOICED ENERGY CHARGES

Description of Risk

ABAG POWER is distributing to each of its Electric Program Members a proportionate share of the Working Capital contributions made by Members in response to Working Capital calls by ABAG POWER and residual funds from operating costs paid by Members during the Electric Program (Balancing Account). These funds were held, in part, in reserve for payment of charges for electrical energy consumed by Members of the Electrical Program during a one-week period in August 2001 when ABAG POWER was not purchasing electricity on behalf of the Electric Program (Gap Period).

As of February 29, 2004, ABAG POWER has not been invoiced for electricity consumed during the Gap Period. Under the Wind Up Agreement, if ABAG POWER receives such a bill, each Member will be required to pay its proportionate share.

Background

Under normal operating conditions, ABAG POWER purchased on behalf of the Members of the Electric Program sufficient energy to meet their estimated needs. Purchases were made from a variety of electricity generators and energy remarketers, under various contractual formats (fixed price, indexed price, indexed price with "floors" and/or "ceilings," etc.), and at various prices. In all instances, one significant factor in the price of electricity is the hour in which it is consumed. Energy during certain "peak" periods was priced considerably higher than at other periods.

In the summer of 2000, the electric market became highly unstable. ABAG POWER was having a difficult time meeting credit requirements which our scheduling coordinator and electricity sellers were imposing on the marketplace. Consequently, on August 2, 2000 ABAG POWER notified PG&E in writing of its difficulties, and actions being taken to rectify the situation. PG&E acknowledged that it had received ABAG POWER's notice, and although it believed that ABAG POWER was in default of its ESP Agreement, PG&E would allow ABAG POWER until August 7, 2000 to resolve the situation. Prior to this deadline, ABAG POWER was able to secure scheduling coordination services and contract for electricity at a reasonable price, without the additional credit requirements imposed by other energy providers and remarketers.

Legal Analysis

From a legal perspective, the matter is a simple collection issue. Since ABAG POWER did not enter into a contract during the Gap Period, there is no "seller" to invoice ABAG POWER for any energy that was consumed. There are only two sources of electricity flowing into the California grid that could have serviced the Electric Program during the Gap Period: the ISO and PG&E.

The energy consumed by the Members could have been supplied through the ISO "imbalance energy." This is a reserve maintained by the ISO when contracted for energy supplies from PG&E and other electric service providers fall below the amount necessary to keep the grid operational. Electricity Program electricity consumption during the Gap Period could have come from this source.

Alternatively, PG&E supplies such a large amount of electricity over any period of time that it could have been supplying part of the power for the Electric Program during the Gap Period.

The risk of incurring the liability is wholly dependent on the ability either of the ISO or of PG&E to "prove" that electricity consumed by Members during this period was supplied by the party making the claim.

ABAG POWER is without sufficient information to evaluate the likelihood of this risk occurring.

ABAG POWER has reviewed the price of imbalance energy for the period in question. Imbalance energy prices tend to be the highest of all prices paid for electricity. Based on the price for imbalance energy an estimate of the amount of electricity that the Electric Program would have consumed during the Gap Period, the maximum exposure is estimated as One Million Four Hundred Twenty Thousand Dollars (\$1,420,000).

Finally, ABAG POWER notes that as time goes on the ability of either the ISO or PG&E to collect the data necessary to generate an invoice and prove a claim diminishes.

B. UDC CHARGES

Description of Risk

From information provided by the Program's billing agent (APS) we believe there may be UDC charges for which neither ABAG POWER nor its Members have been invoiced by PG&E. During the period July 2000 to June 2001 the amount of UDC charges billed to members (and collected by ABAG POWER) is greater than the amount invoiced from PG&E.

ABAG POWER is also aware of one instance in which UDC charges for the affected period were generated by PG&E in connection with an electric account for a Member's streetlight system. These accounts are unique in the PG&E billing system. Electricity consumed by a streetlight system is not metered and is charged on an estimated consumption basis. In the case of which ABAG POWER is aware, the Member had already paid PG&E for the asserted UDC charges.

Based on APS Billing information and information from ABAG POWER's review of the DA Credit's owed by PG&E, ABAG POWER has concluded that the likely total exposure is approximately One Million Six Hundred Thousand Dollars (\$1,600,000).

LEGAL ANALYSIS

PG&E applies UDC charges to individual accounts based on the amount of electricity consumed.

As noted above, streetlight accounts are uniquely billed by PG&E. In the case that has come to ABAG POWER's attention, we believe that the Member has been billed twice for the same UDC charges. Other Members with streetlight accounts may encounter the same situation.

C. ISO ESCROW DEPOSIT AND PX ESCROW DEPOSIT

Description of Risk

The PX Escrow Deposit and ISO Escrow Deposit held by NCPA on behalf of ABAG POWER are subject to reduction or nonrefund. In the case of PX Escrow Deposit, all of the funds may be consumed in the course of settling the PX's bankruptcy claims. The ISO Escrow Deposit is subject to adjustments based on FERC ordered energy price rollbacks (see detailed description in Section D below). The FERC ordered rollbacks can both increase and decrease the ISO Escrow Deposit.

ABAG POWER bought electricity for use by the Electric Program and sold excess capacity into the marketplace at various times. At those instances in which ABAG POWER was purchasing electricity, the FERC ordered price reductions will generate a refund and an increase in the ISO Escrow Deposit. In those instances in which ABAG POWER sold energy into the marketplace, the FERC ordered rollbacks can reduce the amount available from the ISO Escrow Deposit. Based on ABAG POWER's review of the total amount of power sold during the period under consideration by FERC for price reductions, we conclude that the likely reductions do not exceed the amounts currently in the ISO Escrow Deposit.

Under these circumstances, we believe the risk is nominal.

D. DIRECT ACCESS CREDITS

Description of Risk

ABAG POWER is distributing to each of its Electric Program Members a proportionate share of the funds received from PG&E as settlement of ABAG POWER's claim against PG&E for Direct Access Credits incurred during 2000 under the deregulated energy market in California. The Direct Access Credit is a result of the application of a rate formula adopted by the CPUC. The formula includes contemporaneous energy prices and the Direct Access Credit is a by-product of high electricity prices in 2000.¹

The FERC has been engaged in a proceeding to determine whether wholesale prices charged by electricity generators and marketers during 2000 in California were "just and reasonable." FERC has already found that at certain times such prices were not. The FERC

¹ For a detailed description of Direct Access Credits, see Appendix A, "Direct Access Credit."

proceeding is now trying to determine what "just and reasonable" rates should have been during specific times.² The outcome will be an order requiring generators and marketers who overcharged to refund money to purchasers.

In principle, the CPUC has the power to recalculate the Direct Access Credit based on the FERC ordered reduction in electricity prices. However, FERC has no jurisdiction over the CPUC and cannot compel such a recalculation. The result of such a recalculation would be a reduction in the amount of Direct Access Credit owed ABAG POWER.³ The CPUC can undertake a regulatory process referred to as ratemaking in which the ultimate result could be the imposition of a surcharge on Electric Program Member accounts to recoup overpaid Direct Access Credits over a specified time period, or immediately.

This risk exposure is punctuated by §4 of the Stipulation and Release under which PG&E and ABAG POWER are settling the Direct Access Credit claim (Stipulation and Release). §4 states:

*"[ABAG POWER] and PG&E expressly agree that this Stipulation and Release is a compromise and settlement of all claims and matters that are disputed as between the parties involving the 1998 RAP for the period through and including June 30, 2001, all issues that were raised, or could have been raised, in the CPUC Complaint, and all issues that were raised, or could have been raised, in the Claim. In the event that the CPUC issues any future ruling relating to the direct access credits at issue in the Claim, the CPUC Complaint or the 1998 RAP, the parties will use their best efforts to preserve the intent of this Stipulation and Release, consistent with applicable law."*⁴ (emphasis added)

This provision was negotiated when PG&E declined to give ABAG POWER a full indemnity against the possibility that the CPUC will take an action to impose a surcharge to recover Direct Access Credits paid to ABAG POWER (or its electricity members). PG&E agreed that the exposure exists but asserts that it cannot, as an entity regulated by the CPUC, agree to make ABAG POWER whole in the event of an adverse CPUC action. PG&E asserts that an indemnity provision would be characterized as an illegal circumvention (by PG&E) of the CPUC. ABAG POWER acceded to PG&E's argument and §4 is the negotiated compromise.

Background

On December 22, 2003, the U.S. Bankruptcy Court for Northern California, San Francisco Division confirmed a Plan of Reorganization for PG&E (Confirmed Plan). The Direct Access Credit was paid to ABAG POWER under the Stipulation and Release. The Stipulation and Release was approved by the court and is included in the Confirmed Plan as a Class 7 Claim.

During the bankruptcy proceedings, PG&E and the CPUC submitted competing plans for the reorganization of PG&E. Simultaneously, PG&E was pursuing claims challenging certain actions by the CPUC during deregulation (CPUC Proceedings). Further, PG&E filed suit in Federal District Court for Northern California against the CPUC challenging various aspects of the deregulated energy market created under CPUC regulations and guidance. The CPUC

² Pricing occurred on an hourly basis.

³ One estimate of the impact of known (in Spring 2003) FERC ordered reductions on ABAG POWER's Direct Access Credit resulted in a reduction of \$4-5 million in Direct Access Credits owed. ABAG POWER believes the estimate to be reasonable.

⁴ The "1998 RAP" is the ratesetting proceeding described below under the same name. The "CPUC Complaint" is ABAG POWER's initial complaint filed with the CPUC for payment of the Direct Access Credit.

and PG&E reached a Master Settlement Agreement on all pending disputes, including those before the Bankruptcy Court. The Master Settlement Agreement dismissed the lawsuits and the CPUC Proceedings with prejudice, and committed both parties to supporting and implementing what ultimately became the Confirmed Plan. The dismissed CPUC proceedings do not include the 1998 RAP or ABAG POWER's CPUC Complaint. The CPUC action to approve the Confirmed Plan and the Master Settlement Agreement is documented in the opinion issued for Investigation 02-04-026 (Settlement Opinion).

The Master Settlement Agreement between the CPUC and PG&E has the following relevant features:

1. The CPUC agreed to include certain cost components in the CPUC's future regulatory and ratemaking proceedings as they affect PG&E. Such cost components included the sum of \$2.2 billion designated the "regulatory asset." Rates established by the CPUC must be sufficient to (a) support all of the cost components necessary to PG&E's continued viability as an ongoing public utility and (b) amortize the regulatory asset over a period of ten (10) years.
2. Within the constraints of the Confirmed Plan and the Master Settlement Agreement, the CPUC retains its regulatory authority over PG&E.
3. The current CPUC and future CPUCs are bound by the Master Settlement Agreement.
4. The CPUC acknowledges the continuing jurisdiction of the Bankruptcy Court to enforce the Confirmed Plan.

Legal Analysis

The potential CPUC regulatory action on the Direct Access Credit can only be triggered by a FERC ordered reduction in wholesale electricity energy prices for 2000. Only PG&E and a Direct Access Credit recipient have standing to initiate an action to recalculate the Direct Access Credit. PG&E and ABAG POWER are estopped from so doing by §4 of the Stipulation and Release (see below). A recalculation of the Direct Access Credit can in theory be initiated by the CPUC. The impetus for a CPUC action is bureaucratic and triggered by FERC ordered price reductions.

The central question is whether the CPUC can legally do so in the face of ABAG POWER's objections. The issue of recalculating Direct Access Credits based on FERC ordered refunds was raised by PG&E in a ratemaking action before the CPUC (Application 98-07-003, the "1998 RAP" filed in 1998). The Administrative Law Judge (ALJ) issued a draft decision on April 3, 2003 but the CPUC has not taken any action on it and it is not currently on the CPUC agenda for consideration, public hearing or further action.⁵

The 1998 RAP - Draft Decision states in pertinent part:

"In our opinion it would be unreasonable to recompute the [Direct Access] credit should FERC order refunds. We are confronted, initially, with three unknown factors: whether FERC will order refunds: when FERC will order refunds (and when the order become[s] final), and the amount of those refunds.¹ As of this writing, FERC has the matter under consideration. Any order of refunds, if substantial, is expected to be appealed. It is impossible to predict the date of a final order. The period in question, December 28, 2000 to January 18, 2001, is two years old and counting. It is unfair for

⁵ No action can be taken without CPUC approval. Draft ALJ decisions on deregulation matters have had a mixed reception before the CPUC. Some have been adopted as presented. Others have been subject to substantial revision. The draft decision is Opinion Adopting a Post Power Exchange Direct Access Credit for Pacific Gas and Electric Company (1998 RAP - Draft Decision).

ratepayers who paid their utility bills two years ago to be subject to an unknown liability to be paid at an unknown future date. We need not elaborate on the intensive effort required by PG&E to recompute individual bills nor the intensive efforts and spent resources of end users to verify those recomputed bills. Because we deny PG&E's proposal we do not reach the question of whether approval of the proposal would constitute retroactive ratemaking."

ⁱ When we speak of refunds in this context, we refer not to money going back to DA [direct access] customers, but to a recommendation of their credit. If a refund is ordered, the credit would have been less and the DA customer would have been overpaid by PG&E thereby causing a repayment to PG&E.

The same logistical objections raised by the ALJ to retroactive reductions in Direct Access Credits still stand and are amplified by the passage of yet another year since issuance of the 1998 RAP – Draft Decision and without further action by FERC.⁶ Further, the legal barriers to "retroactive ratemaking," which the draft decision avoids, become a live issue.

Independent of the arguments made in the 1998 RAP - Draft Decision, a strong legal argument can be made that the CPUC is estopped by the Settlement Opinion and Master Settlement Agreement from reducing the amount of the Direct Access Credit paid to ABAG POWER.

The Settlement Opinion makes the following policy finding: "It is in the public interest that PG&E emerge from bankruptcy promptly....To emerge from bankruptcy PG&E should pay its creditors. *All allowed claims should be paid in full.* (emphasis added)"⁷ On the date of the Settlement Decision, ABAG POWER's Stipulation and Release was an "allowed claim" and part of the record before the CPUC. It will be difficult for the CPUC to defeat the argument that it is estopped from taking any (otherwise permitted) action that effectively modifies the Stipulation and Release or reduces the payment required by the Stipulation and Release. In addition, the Master Settlement Agreement states: "[PG&E and the CPUC] agree not to contest the validity and enforceability of [the Master Settlement Agreement], the [Confirmed Plan] or any order entered by the [Bankruptcy Court] contemplated by or required to supplement [the Master Settlement Agreement and the Confirmed Plan]."⁸

Ancillary Analysis

In addition to the "logic" of a bureaucratic recalculation of the Direct Access Credits in response to the anticipated FERC ordered price reductions, there might be pressure on the CPUC to recover Direct Access Credits to reduce general utility rates. In response, one can raise the objection stated in the 1998 RAP – Draft Decision that the costs to recalculate and recover "overpaid" credits may well exceed the recovery. Finally, please note that the post-bankruptcy CPUC ratemaking structure for PG&E includes the "regulatory asset." Under the terms of the Confirmed Plan and the Master Settlement Agreement, the amount of the regulatory asset which must be amortized by ongoing electric rates will be reduced by any monies actually recovered by PG&E as a result of the same FERC price rollback.⁹ The direct

⁶ Although, the contested time period misses most of the times during which ABAG POWER's Direct Access Credit was generated. The same legal arguments apply and the FERC proceeding has expanded the timeframe for potential price rollbacks to include more of the period in which ABAG POWER's credits were "generated."

⁷ Settlement Decision, p. 78.

⁸ Master Settlement Agreement, p. 18, §21.

⁹ Master Settlement Agreement, pp. 8-9, §2.d.

effect of the FERC ordered rollback brings significant rate relief under the Confirmed Plan.¹⁰ In the context of generalized rate relief, it appears doubtful that the CPUC would be willing to undertake the ironic step of imposing a surcharge on certain classes of customers (including local government entities such as ABAG POWER's electricity members) in order to wring out the last bitter drop of savings generated by the FERC ordered refunds. Another impediment to such action by the CPUC is the specter of resurrecting the public debate about California's failed energy deregulation program.

Conclusion

The CPUC has the theoretical ability to reduce the Direct Access Credits paid to ABAG POWER. However, ABAG POWER can pose the following legal argument in position: (a) the CPUC is estopped from so doing by the CPUC's findings and actions in reaching the Master Settlement Agreement with PG&E, and the CPUC's support for the Confirmed Plan under which the credits were paid, and (b) the logistical and equity issues raised in the 1998 RAP – Draft Decision. In the absence of any motivation to undertake such a step other than bureaucratic purity of process, ABAG POWER's opinion is that the risk is nominal.

¹⁰ Master Settlement Agreement estimates a potential recovery by PG&E of _____ (\$_____) in FERC ordered price reductions.

EXHIBIT A TO ATTACHMENT D

Allocation of Estimated Contingent Liabilities.

This table illustrates the allocation of ABAG POWER's estimate of the Electric Program liability for the denoted charges among Electric Program members. Allocated amounts have been rounded to the nearest 10 dollars. Please see Attachment D for an explanation of the methodology and basis for this

Members	(A)	(B)	(D)	Total
	Uninvoiced	UDC Charges (2)	Direct Access	
	Energy Charges (1) \$1,420,000	UDC Charges (2) \$1,600,000	Credits (3) \$4,676,000	
City of Albany	\$ 4,920	\$ 5,550	\$ 9,350	\$ 19,820
Town of Los Altos Hills	470	530	1,220	2,220
City of Antioch	74,030	83,420	164,090	321,540
City of Arcata	5,360	6,040	15,470	26,870
Town of Atherton	2,860	3,220	8,000	14,080
City of Benicia	18,160	20,470	50,600	89,230
City of Berkeley	4,060	4,570	55,190	63,820
County of Butte	28,680	32,310	107,610	168,600
City of Cloverdale	7,700	8,670	29,570	45,940
County of Monterey	78,860	88,860	151,450	319,170
County of Contra Costa	207,960	234,320	778,930	1,221,210
City of Cotati	3,960	4,460	10,690	19,110
City of Cupertino	20,620	23,230	49,040	92,890
City of Daly City	62,020	69,880	357,930	489,830
City of Davis	3,320	3,740	3,720	10,780
City of El Cerrito	5,130	5,780	16,530	27,440
City of Foster City	19,770	22,280	54,620	96,670
Golden Gate Bridge District	19,880	22,400	101,650	143,930
City of Gonzales	5,630	6,350	15,130	27,110
City of Half Moon Bay	2,840	3,200	7,180	13,220
H.A.R.D.	12,630	14,230	38,750	65,610
City of Hercules	7,890	8,890	22,280	39,060
Town of Hillsborough	11,460	12,910	30,760	55,130
Housing Auth. Co. of Alameda	1,880	2,120	6,690	10,690
City of Los Altos	7,760	8,740	20,970	37,470
Los Trancos Co. Water District	1,010	1,140	1,330	3,480
City of Menlo Park	17,380	19,590	56,130	93,100
City of Millbrae	7,890	8,890	12,770	29,550
City of Mill Valley	15,860	17,870	50,970	84,700
City of Milpitas	16,580	18,680	79,120	114,380
Town of Moraga	2,660	3,000	3,660	9,320
County of Napa	21,800	24,560	109,150	155,510
City of Newark	13,140	14,810	25,400	53,350
City of Orinda	2,410	2,720	5,150	10,280
City of Pacifica	12,260	13,820	28,160	54,240
City of Patterson	9,570	10,780	62,570	82,920
City of Petaluma	54,380	61,270	96,470	212,120
City of Pinole	14,220	16,020	72,080	102,320
City of Pleasanton	43,290	48,780	107,930	200,000
R.A.F.C.	17,870	20,130	64,580	102,580
City of Salinas	40,070	45,150	58,300	143,520

EXHIBIT A TO ATTACHMENT D

Allocation of Estimated Contingent Liabilities.

This table illustrates the allocation of ABAG POWER's estimate of the Electric Program liability for the denoted charges among Electric Program members. Allocated amounts have been rounded to the nearest 10 dollars. Please see Attachment D for an explanation of the methodology and basis for this

Members	(A) Uninvoiced Energy Charges (1) \$1,420,000	(B) UDC Charges (2) \$1,600,000	(D) Direct Access Credits (3) \$4,676,000	Total
City of San Carlos	10,380	11,700	27,170	49,250
City of San Leandro	49,380	55,640	139,200	244,220
City of San Mateo	44,790	50,460	117,720	212,970
County of San Mateo	148,120	166,900	582,550	897,570
City of San Pablo	9,370	10,550	23,580	43,500
City of Santa Rosa	82,740	93,230	188,680	364,650
City of Saratoga	4,360	4,920	10,060	19,340
County of Sonoma	7,230	8,150	15,390	30,770
South Co. Fire Authority	910	1,020	3,800	5,730
City of Union City	2,880	3,240	17,130	23,250
City of Vacaville	7,770	8,760	26,690	43,220
City of Vallejo	91,810	103,450	346,500	541,760
West County Wastewater Dist.	20,620	23,240	131,420	175,280
Town of Windsor	24,810	27,950	93,390	146,150
City of Winters	6,570	7,410	11,540	25,520
Total	\$ 1,419,980	\$ 1,600,000	\$ 4,676,010	\$ 7,695,990

Notes:

(1) Allocated by kWh usage

(2) Allocated by kWh usage

(3) Allocated on CTC Credit Reversals. Represents PG&E's estimate of the possible reduction in the CTC credits due to the FERC price mitigation hearings.

ABAG POWER Electric Program Total Distributions

(as of 4/15/04)

Members	Total Distribution (4)
City of Albany	\$ 51,165
Town of Los Altos Hills	10,991
City of Antioch	824,494
City of Arcata	91,754
Town of Atherton	50,170
City of Benicia	290,730
City of Berkeley	282,431
County of Butte	550,263
City of Cloverdale	153,473
County of Monterey	832,306
County of Contra Costa	3,664,549
City of Cotati	68,760
City of Cupertino	288,830
City of Daly City	1,563,507
City of Davis	34,903
City of El Cerrito	98,522
City of Foster City	286,754
Golden Gate Bridge District	452,392
City of Gonzales	96,840
City of Half Moon Bay	42,810
H.A.R.D.	240,080
City of Hercules	146,064
Town of Hillsborough	199,226
Housing Auth. Co. of Alameda	44,810
City of Los Altos	125,285
Los Trancos Co. Water District	12,016
City of Menlo Park	307,678
City of Millbrae	89,102
City of Mill Valley	299,065
City of Milpitas	400,734
Town of Moraga	27,153
County of Napa	510,755
City of Newark	183,254
City of Orinda	39,051
City of Pacifica	162,253
City of Patterson	286,450
City of Petaluma	582,373
City of Pinole	311,543
City of Pleasanton	614,341
R.A.F.C.	414,351
City of Salinas	366,943
City of San Carlos	151,412
City of San Leandro	715,160
City of San Mateo	660,825
County of San Mateo	2,937,453
City of San Pablo	141,840
City of Santa Rosa	1,052,609
City of Saratoga	64,934

ABAG POWER Electric Program Total Distributions **(as of 4/15/04)**

Members	Total Distribution (4)
County of Sonoma	101,352
South Co. Fire Authority	21,189
City of Union City	76,861
City of Vacaville	164,394
City of Vallejo	1,741,413
West County Wastewater Dist.	662,852
Town of Windsor	464,451
City of Winters	85,228
Total (4)	24,140,144

Note: (4) Does not include
Members Balancing Account, or
ISO and PX escrow deposits with
NCPA.